**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017

ANSWERS TO ADMINISTRATIVE LAW JUDGE'S RULING SEEKING ADDITIONAL INFORMATION ON THE DISTRIBUTION PLANNING PROCESS BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

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Pursuant to *Administrative Law Judges' Ruling Seeking Additional Information from Investor-Owned Utilities on their Distribution Planning Process* (Ruling), filed March 9, 2023, Pacific Gas and Electric Company (PG&E) provides answers to the questions presented in Attachment 1 of the Ruling.

I. DEFINITION FOR THE TERM "DISTRIBUTION PLANNING PROCESS" (DPP)

PG&E supports the high-level definition adopted by the Competitive Solicitation Framework Working Group in the Integrated Distributed Energy Resources (IDER) proceeding (Rulemaking (R.) 14-10-003): The electric utilities' distribution planning process evaluates and specifies projects to ensure the availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system. Electric utility distribution planning engineers utilize: (1) forecasts of electric demand; (2) power-flow modeling tools to simulate electric grid performance under projected conditions to forecast distribution capacity and voltage requirements; and (3) engineering expertise to identify and develop distribution capacity and voltage management additions that meet forecast conditions and address identified distribution capacity and voltage requirements, including safety and reliability deficiencies.[1]

For a more detailed definition, PG&E provides the following additional information:

[1] *Competitive Solicitation Framework Working Group Final Report Filed by Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company*, p. 9. Filed August 1, 2016 in R.14-10-003.

The Distribution Planning Process (DPP) is a set of engineering methods and criteria for determining the adequacy of existing electric primary[2] distribution system capability and forecasting the need for additional facilities.

The DPP includes the following analyses to identify grid needs:

- Reviewing historical loading on the distribution system;
- Reviewing new applications for service;
- Performing Large Load Studies for new customer loads;
- Creating 10+ year load forecasts for substation transformers and circuits;
- Creating 3-year load, voltage, and power factor forecasts for each node on a distribution circuit; and,
- Creating load forecast reports on an annual basis to develop the Grid Needs Assessment (GNA) Report.

The DPP then studies any issues identified in the analyses above and evaluates available solutions to address the system deficiencies. Several alternatives are considered to determine the best option, including:

- Identifying transfers to reconfigure the distribution system to accommodate new load;
- Installing line capacitors to correct power factor;
- Installing voltage regulating devices to maintain adequate voltage;
- Building and reinforcing loops, back-ties, and emergency capacity;
- Rebuilding existing circuits with larger conductor;
- Building new circuits from substations;
- Installing or replacing substation transformers; and
- Building new substations.

[2] PG&E's distribution system is defined as facilities operated at voltages less than 50 kilovolts (kV). This system is further divided into two parts: (1) the primary distribution system; and (2) the *secondary* distribution system. Any equipment operating at or above 4 kV is considered part of the primary system.

The identified preferred options are prioritized through the Investment Planning Process with capital funding requested through the General Rate Case (GRC). Once funding is approved, PG&E determines the allocation of capacity budget towards individual distribution infrastructure projects based on the latest available information on system needs. Please see Section III below for more detail on planned investments.

II. EXISTING DPP

A. Description of PG&E's Current DPP and Timeline for the Infrastructure Improvements Needed for a High-Electrification Future

PG&E's current DPP examines a 13-year ***forecast*** horizon at the circuit and bank level. PG&E is actively exploring modeling a longer forecast horizon than 13-years as a part of its grid modernization efforts for planning tools.

PG&E's current DPP generally has a 5-year ***planning*** horizon at the circuit and bank level. This planning horizon is appropriate given the typical timeline to complete the scope of work for most distribution capacity improvements (see table below). However, there are exceptions such as long-lead time investments like building a new substation, especially where California Environmental Quality Act (CEQA) oversight is required.[3] For these longer lead-time investments, the permitting process often needs to start more than 5 years ahead of identifying the project. Therefore, for these limited long lead-time cases, PG&E will review and identify projects beyond the 5-year planning horizon on an annual basis to start the planning (e.g. permitting) process as early as necessary.

PG&E's current DPP generally has a 3-year forecast and planning horizon at the line section level given the shorter timelines for line section improvements.

Typical timelines are identified below for the construction/implementation of each type of distribution capacity improvement on the primary system:

[3] For *example*, the Estrella substation was identified in the 2017 GRC and is currently still in CEQA review.

Scope of Distribution Capacity Improvement	Typical Timeline
Distribution line work to increase capacity or reconfigure circuits	12 to 36 months
Add a new circuit from an existing substation	24-36 months
Add or replace a substation transformer at an existing substation	36-48 months
Build a new substation	5-7 years depending on agency with CEQA oversight responsibility

Note that these timelines do not include any secondary system work which may be required to accommodate added electric load at a customer site. Such work can include secondary service conductor replacements, secondary transformer replacements, or the addition of new secondary transformers. The timeline for implementing such replacements is generally shorter than the timelines considered in distribution planning. These replacements are not part of the DPP (See Response I) and are instead identified as part of the New Service Application process and managed within the Service Planning Process.

B. Discussion on how PG&E Plans for a High Electrification Future

The plan for a high electrification future includes the following measures:

- Use of California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) system-level electrification load growth scenarios as part of the annual forecast update, including consideration of high Transportation Electrification (TE) scenarios.[4]
- Improvements to Electric Vehicle (EV) disaggregation methodologies based on increased understanding of adoption propensities, which enable a more accurate IEPR forecast allocation. See Response II.D for more information on EV sectors.

[4] *Email*, "High DER: IEPR Datasets Approval for 2023 GNA/DDORs (R.21-06-017)", Peterson, Rob; July 28, 2022

- Inclusion of multiple EV hourly load profiles in the forecast so that the impact of new EV loads across each hour is accurately represented and the impact on the local circuit and bank peak is not overstated.
- Coordination with PG&E's Service Planning and Fleet teams to obtain accurate hourly load profiles from new EV customers. Engaging with customers in cases where a shifted profile might allow interconnection without capacity work or ahead of planned capacity work.
- Integration of projects in a geographical area to obtain project cost reductions through design and labor efficiencies.

PG&E also currently incorporates plans for a high electrification future managing flexible loads into the forecasts as follows:

- In PG&E's load forecasts, managed charging is applied via the EV Hourly Load Profile, aka "load shape". It is not a reduction in the overall peak magnitude of each new EV load adjustment.
- Managed Charging is assumed for the residential EV home charging load profile (2am peak). This profile was provided by Portfolio Resource Forecasting and assumes a portion of residential charging is managed charging based on the EV rate.
- The Direct Current Fast Charge (DCFC) shapes in our forecast are based on actual DCFC charging data. To date, usage data has generally indicated that EV rates do not have a notable effect on shifting usage for DCFC.
- The Fleet load shape assumes off-peak charging. Historical usage data to date indicates fleets charge when they are not using vehicles; they do not manage their charging. The load shape is thus based on what time periods vehicles are not used, more than rates.
- Presently there is no available technology across all vehicles on a bank or circuit to perfectly spread-out charging and avoid creating a new peak. Automated Load Management (ALM) can result in charging becoming grouped in certain hours and can create a new load peak. A smart program would be required to coordinate each vehicle with other vehicles charging on the same circuit or bank to spread out this load.

- Historical usage data indicates that today's EV rates have relatively low-cost differentials between periods that do not sufficiently incentivize time shifting enough to make up for customer inconvenience of not being able to charge when needed for Fleets and DCFC.
- Assuming load shifting when historic usage has not supported this assumption creates a risk of under forecasting. Instead, PG&E intends to examine managed load shapes for scenario analysis only until these capabilities are more fully understood.
- PG&E is currently in the planning phase of the Distributed Energy Resource Management System (DERMS) deployment with initial focus on use cases related to managing dynamic distribution grid constraints through the control of participating Distributed Energy Resources (DERs) including flexible loads. PG&E expects to pilot initial DERMS use cases at a limited scale by 2024 and will plan to scale up in subsequent years pending results. Further information on DERMS are included in Response II.G.

C. New or Changes to Existing Commission Decisions or Policy Guidance to Serve Electrification Load Growth

While PG&E plans for a high electrification future, it recognizes that controlling costs to ensure ratepayer affordability is an integral part of the investment planning process and GRC. PG&E seeks to drive long term sustained efficiencies to offset future cost pressures associated with increased capital investment requirements, changing risk profiles, and external demands with the goal of maximizing risk mitigation while minimizing impact to customer utility bills.

However, the Commission should acknowledge that additional capacity investments are needed to meet the state's electrification goals and growing demands. This will likely need to include both ratepayer funding and alternative sources of funding for a variety of capacity investment types (including DERs). PG&E is not requesting that the High DER Future proceeding directly authorize additional funding; rather PG&E recommends that the proceeding issue findings that identify the need for additional investments through studies such as Kevala's Electrification Impact Study, and determine the policy changes necessary to obtain funding for these investments.

For context, PG&E's 2023 GRC application requested funding to support capacity investments for a four-year period from 2023-2026. However, this funding request will not be sufficient on its own to meet capacity investment needs during that period nor the state's longer term electrification goals for 2030 and beyond. PG&E's 2023 GRC request was based on the 2019 CEC IEPR, which has a significantly lower Transportation Electrification forecast than state policy goals.[5] Subsequent updates to the IEPR forecast anticipate significantly accelerating load growth in electrification, which are not reflected in the PG&E's 2023 GRC application. In addition, while the 2023 GRC approves funding for 2023-2026 capacity projects; as explained above, certain projects whose needs materialize after 2026 may need funding sooner due to longer lead times. Lastly, there has also been a significant increase in capacity requests for new service from customers and DER developers, particularly to support TE charging infrastructure. In summary, the 2023 GRC distribution capacity proposal represents only about ~50% of known capacity projects due to affordability considerations, significantly lower electrification growth forecasts, and the increasing receipt of new service applications that require capacity work (e.g., DCFC charging sites). Therefore, additional funding beyond PG&E's 2023 GRC request will be necessary to meet both near-term needs and the state's long-term electrification goals.

First, the Commission should explore a ratemaking policy to meet the growing electrification need, such as a two-way balancing account for capacity investments. The IOUs could continue to provide forecasts for approval in the GRC that can provide timely cost recovery, yet where applicable, preserve the Commission's ability to later review actual spending against the adopted amounts. In its 2023 GRC, PG&E filed a motion to propose revisions to the Transportation Electrification Balancing Account (TEBA), which was rejected for procedural reasons.[6] However, the Commission should consider whether a balancing account in a separate

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[5] *See* Final *2019* Integrated Energy Policy Report, adopted February 20, 2020. Available online: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr

[6] *See* Motion of *PG*&E for Permission to Submit Supplemental Testimony, filed October 8, 2021 in Application 21-06-021.

application or another proceeding is possible prior to PG&E's next GRC filing. The Commission could utilize balancing accounts that establish reasonable forecasts of costs approved by the Commission to be included in rates on a timely basis. Costs recorded to the balancing account would be subject to audit, underspent amounts would be returned to customers, and costs incurred above established spending thresholds would be subject to a demonstration of incrementality or reasonableness. Such a construct can provide a review of customer benefits when there are circumstances beyond the utility's control that require higher spending, or when accelerating work into the near term is more cost efficient or provides better service. Examples of such approved constructs currently in place are the Vegetation Management Balancing Account (VMBA) that requires a showing of reasonableness prior to recovery of costs above 120 percent of adopted amounts. Similarly, the Wildfire Mitigation Balancing Account (WMBA) requires a showing of reasonableness prior to recovery of costs above 115 percent of the adopted amounts, as well as a showing of reasonableness if the undergrounding or overhead system hardening costs exceed 115 percent of the adopted overhead and underground unit costs.

Second, PG&E also recommends that this proceeding investigate additional potential funding sources. Alternative funding sources could include the re-allocation of existing customer program funds (e.g., SGIP[7], LCFS[8]) to consider the provision of distribution capacity as part of the program. In addition, mechanisms to enable customers to self-fund projects to reserve capacity should be explored, in which customers would be refunded over time based on collected distribution revenue.

Third, for long-lead time investments, such as substation projects, it is necessary to consider the projects proactively in both the DPP and GRC to begin the licensing and permitting processes long before the need materializes so that it can be completed in time to meet the

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7 For example, PG&E's Self-Generation Incentive Program (SGIP) does not currently include funding for necessary distribution capacity upgrades.

8 For example, *revisions* to Decision D.20-12-027 to permit IOUs to also use Low Carbon Fuel Standard (LCFS) funding for distribution capacity upgrades.

forecasted need. Substations can take many years to construct and delays to the permitting process can significantly impede the ability to meet loads in the areas.[9] Furthermore, the funding necessary to support this work exceeds the 4 year GRC window. Revising CPUC policies to streamline the process and require swift decision making with regards to permitting (e.g., GO-131D), especially for facilities needed to meet electrification needs, would help facilitate the IOUs' ability to meet the state's electrification needs. In addition, since these projects often span across the funding windows of more than one GRC filing, the CPUC should consider how to address and approve funding for the entire project costs, rather than in a piecemeal manner based upon GRC windows.

Fourth, PG&E believes load flexibility has significant *potential* to help customers meet their capacity needs. However, it is still premature to plan our electrification future based on load flexibility. Electric Rates Demand Flexibility OIR track B (R.22-07-005) proceeding will address development of a set of guidelines for future time-dependent rate applications necessary to be filed by large IOUs to comply with CECs new, amended Load Management Standards (LMS). It is far too early to try determining if time-dependent rates and charges that eventually are adopted will contribute towards meeting distribution capacity needs. Regardless, *requirements* for flexible load should be considered, including in customer program design, to mitigate the ratepayer impacts of electrification. PG&E cautions that relying solely on price signals and incentives, rather than requirements, may not be a financially viable way to reduce overall ratepayer impacts.

D. Utility Assumptions on Load Projections and Methods to Identify Electric Vehicle Customers and Loads

<u>Building Electrification (BE)</u>

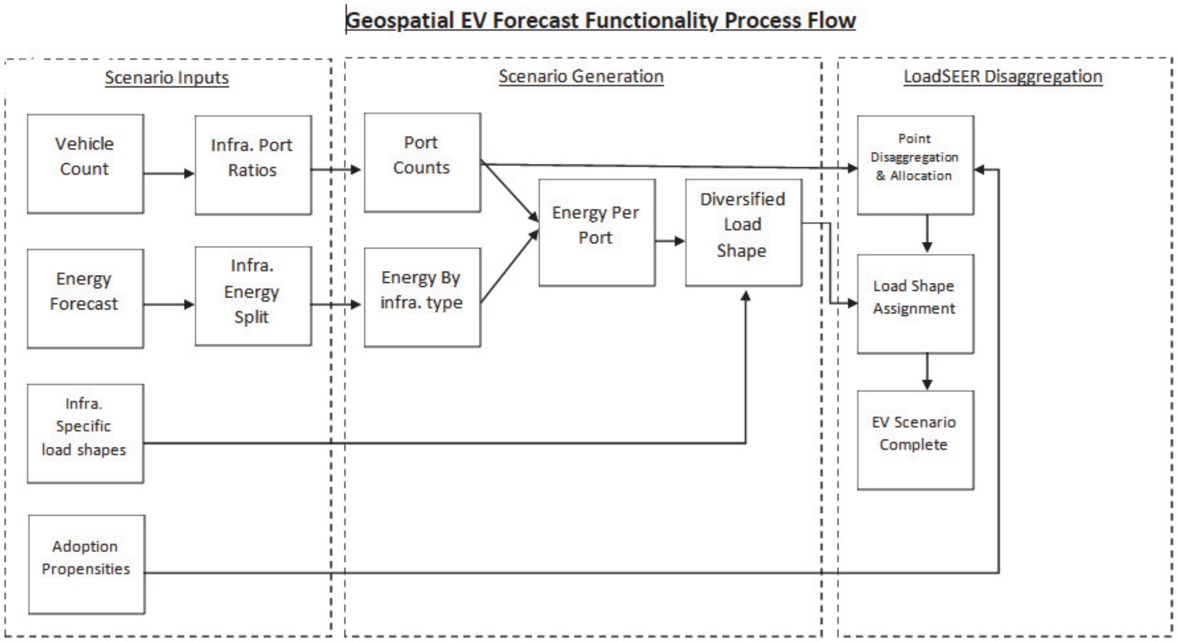
BE load projections are primarily driven by CPUC-approved forecast scenarios, and in the case for the 2022-2023 DPP, an IEPR Mid Additional Achievable Fuel Substitution (AAFS) forecast was developed to enable utilities to plan for building electrification load growth aligned

[9] For *example*, SCE's Alberhill and PG&E's Estrella projects have incurred significant delays.

with state goals and BE policy. The base forecast is derived from both Advanced Metering Infrastructure (AMI) aggregation and substation telemetry. Since all the existing building electrification loads are already included in the base forecast, the IEPR AAFS growth from year to year is calculated and modeled. The load growth is spatially disaggregated on the system and is proportional to circuit net loading.

Transportation Electrification

TE load projections are primarily driven by CPUC-approved forecast scenarios, and in the case for the 2022-2023 DPP, a combination of the IEPR High TE forecast and the High Electrification Inter-Agency Working Group (HEIAWG) forecast which was developed to enable utilities to plan for higher electrification load growth which is better aligned with state goals and TE policy. Electric vehicle loads move freely across the system. The base forecast is derived from both AMI aggregation and substation telemetry. Since all the electric vehicle load is already included in the base forecast, the IEPR growth from year to year is calculated and modeled. As part of the DPP, the approved future TE loads accounting for new connection applications are subtracted from the forecasted IEPR load growth. The remaining load growth is spatially disaggregated on the system based on propensity modelling performed on the main transportation electrification charging infrastructure types; residential level 1 (L1) and level 2 (L2) charging, Public Direct Current Fast Charing (DCFC) and L2, Fleet Charging, and workplace charging. (See "Geospatial EV Forecast Functionality Process Flow").



Light Duty EVs – Forecasted charging demand for light duty EV is split among Residential L1, Residential L2, Public DCFC, Public L2, and Workplace L2 charging. Each charging infrastructure type has a diversified load shape assigned. The load shapes are normalized so that as an energy forecast for each infrastructure type is applied, an hourly power demand is derived. The infrastructure energy demand split is influenced by the AB 2127 assessment. The following percentages are used to allocate total Light Duty EV Energy demand across the main Light Duty EV infrastructure charging types (See table "User input 3 – Energy Consumption Parameters").

User input 3 - Energy Consumption Parameters

Energy consumed charging in public as a percentage of total energy consumed charging in all

Input name	Input value
Average Annual Energy Consumption (kWh/ EV-year)	4271.3
Residential L1 Charging Energy Consumption Percentage (%)	6%
Residential L2 Charging Energy Consumption Percentage (%)	58%
Workplace Charging Energy Consumption Percentage (%)	16%
Public L2 Charging Energy Consumption Percentage (%)	5%
Public DCFC Charging Energy Consumption Percentage (%)	15%

Each charging infrastructure type is individually analyzed to identify potential geographic growth points and adoption propensity modelling is performed to support an agent simulation as part of the disaggregation process. The forecasted quantity of charging infrastructure ports that are available for disaggregation is an output of the quantity of forecasted Light Duty EVs and the ratios of vehicles to necessary charging ports informed by AB 2127 and EVI-Pro modelling.

For public charging and shared private/workplace charging the ratios above result in the number of ports to be assigned during disaggregation. The respective energy split per infrastructure type is used to assign an energy forecast to each assumed adopted charging port. For example, for every 39 vehicles adopted, one workplace level 2 charger port will be forecasted (see table "User input 5 – Non-Residential Charging Network") and 16% of all Light Duty EV energy forecasted will be assigned to all resulting workplace L2 ports (See table "User input 3 – Energy Consumption Parameters"). Proximity to highway corridors and activity locations/amenities are high indicators of public charging locations. Potential workplace charging locations rely on business registration data.

User input 5 - Non-Residential Charging Network

The ratio of total number of charging ports to the total number of EVs in PG&E

Input name	Input value
Port : EV Ratio - Workplace L2	1/39
Port : EV Ratio - Public L2	1/65
Port : EV Ratio - Public DCFC	1/216

Example - Non-Residential Charging Network

Year	EVs	Work L2	Pub L2	Pub DCFC
2023	43,878	1,125	675	203
2024	105,756	2,712	1,627	490
2025	171,744	4,404	2,642	795
2026	311,547	7,988	4,793	1,442
2027	488,341	12,522	7,513	2,261
2028	695,990	17,846	10,708	3,222
2029	932,019	23,898	14,339	4,315
2030	1,190,428	30,524	18,314	5,511
2031	1,770,026	45,385	27,231	8,195
2032	2,384,029	61,129	36,677	11,037
2033	3,019,911	77,434	46,460	13,981
2034	3,682,902	94,433	56,660	17,050
2035	4,372,933	112,126	67,276	20,245

For residential charging access, housing demographics and census data are used in collaboration with academic literature and EVI-Pro modelling to develop the assumptions that 36% of personal Light Duty EVs have access to Residential L1 charging and 48% have access to residential L2 charging (See table "User input 4 – Residential (Non-MUD) Charging Access"). These percentages and the light duty vehicle adoption forecast are used to forecast the number of L1 and L2 chargers for disaggregation with Light Duty EV energy demand of 6% and 58% (See table "User input 3 – Energy Consumption Parameters"), respectively, assigned to these charging locations.

User input 4 - Residential (Non-MUD) Charging Access

The percentage of total EVs that have access to residential charging. This input is

Input name	Input value
Residential L1 Charging Access	36%
Residential L2 Charging Access	48%

Example - Residential (Non-MUD) Charging Access

Year	BEVs	Res L1	Res L2
2023	43,878	15,880	20,957
2024	105,756	38,273	50,510
2025	171,744	62,155	82,027
2026	311,547	112,750	148,799
2027	488,341	176,732	233,238
2028	695,990	251,881	332,414
2029	932,019	337,301	445,144
2030	1,190,428	430,820	568,564
2031	1,770,026	640,578	845,387
2032	2,384,029	862,788	1,138,643
2033	3,019,911	1,092,915	1,442,348
2034	3,682,902	1,332,854	1,759,001
2035	4,372,933	1,582,579	2,088,569

Medium & Heavy- Duty EVs (MDHD) – To support forecasting of future MDHD EV growth, PG&E commissioned a research study to identify fleet locations in PG&E's service territory. For identification of fleets, this analysis used FleetSeek, the California Air Resources Board's (CARB) EMFAC database, and the Federal Transit Administration's National Transit Database. This resulted in a collection of address and census block locations and associated vehicle types and quantities that are used for forecasting future fleet electrification. The MDHD EV quantities forecasted are provided by the approved planning forecast and the average vehicle energy demand is based on the vehicle consumption in the IEPR High TE.

E. Constraints or Barriers to Achieving Adequate and Optimal Planning; PG&E's Current Plans for Addressing Known Capacity Constraints

The future of the grid is complex and changing as electrification, climate change and California's goals drive accelerating multi-dimensional needs. PG&E is adapting and holistically managing the grid to address these needs in a comprehensive and optimal way to provide safe and reliable service for all customers while managing affordability. As it does so, PG&E encounters the following challenges in planning for high electrification:

- Funding for capacity work is presently insufficient for the number of applications for service that require capacity projects. However, funding all capacity work through rates will be a burden to customers and a strain on affordability.
- Customers often do not understand their own load requirements and/or are unable to provide an accurate assessment of their new load demand or hourly load profile, forcing utilities to determine a reasonable load demand estimate via its own research and heuristics.
- Transmission constraints may limit the capacity available on the distribution system until such time as the transmission system project goes through the Transmission Planning process and obtains CAISO approval.
- Timing and magnitude of large fleet and DC fast charging load is lumpy (e.g.- 6 MW of DC fast charging load all at once rather than gradual load growth).

- Time lag from permitting processes (e.g.- GO-131D), especially for facilities needed to meet electrification needs can be significant.
- Uncertainty around customer behaviors impact DPP assumptions (e.g., it can be assumed that all fleets will eventually electrify, but when will each fleet operator make the decision to do so?).
- Demand flexibility that relies solely on price signals and incentives, rather than requirements and new control technology, may not influence customer load and avoid capacity upgrades (unless such incentives/price signals are extreme and likely not cost-effective).

As described in Sections II.F, G, and H, below, PG&E is investing in tools and improving community engagement to better forecast and plan for grid needs, enable automated load management, and communicate to customers where the grid can accommodate load. PG&E is also piloting real-time rates to better understand the impact of incentives for demand flexibility. The ultimate objective is to deliver optimal outcomes for our communities and help prepare our grid for the future.

F. Primary Risk Factors for Near-Term Capacity Constraints and Measures Taken to Mitigate These Risks

Primary risk factors for near-term capacity constraints include:

- Affordability remains challenging for many customers, limiting the near-term ability to make pro-active capacity investments to meet potential future electrification needs.
- Demand for materials and labor also outpaced supply due to national and global supply chain issues affecting the availability of transformers and conductor, which has constrained construction timelines.
- Redirection of workforce, material, and other resources to urgent safety and rebuild work in the communities as part of our Community Wildfire Safety Program efforts, along with responses to multiple major emergencies.

PG&E has been working to meet ever-growing energy demand while continuing to mitigate wildfire risk and complete safety-related work. We have invested nearly $1 billion in capacity upgrades between 2015 and 2021 and are gearing up to invest significantly more in the coming years. We are taking a more holistic and longer-term view of resource requirements to avoid these types of constraints in the future.

In addition, PG&E is:

- Guiding customers to areas where capacity is available on the system;
- Exploring technologies (e.g. Automated Load Management) where customer flexibility is possible in order to efficiently utilize existing capacity;
- Exploring technologies to develop solutions to manage localized capacity constraints (e.g. DERMS);
- Combining capacity upgrades with other grid solutions like asset health investments and system hardening to address multiple needs at once through Integrated Grid Planning;
- Exploring ways in which customers can self-fund projects. This would allow PG&E to collect money upfront from customers for standard facility upgrades, build the capital projects with those funds, and refund it over time based on collected distribution revenue; and,
- Accessing non-traditional funding sources (such as the Department of Energy's Grid Innovation and Resilience Program and other federal grants) to fund capacity and resilience projects in partnership with customers and communities.

Lastly, as we adopt an integrated grid planning approach, we will prioritize our electric capital work across multiple objectives – reducing wildfire risk, adding capacity, improving asset health, and improving reliability – and seek opportunities to address multiple needs with a single solution. Specific to capacity, we will focus on projects required to connect customers while also addressing forecasted loading on the electric system. When prioritizing these projects, we will use similar criteria to what is used currently, including project status, duration of time a customer has been waiting to be connected, etc.

G. PG&E's Current Access and Plans to Acquire Software, Data, and Tools to Support Planning and Modeling

PG&E is currently transitioning to an upgraded versions of LoadSEER and CYME, two of the forecasting software tools used in the DPP. With the upgrade, there will be integration between the tools as well as several changes and enhancements that will allow for maximizing capacity utilization. These include forecast load profiles increasing from 576 to 8,760 hours, the ability to analyze multiple forecast scenarios for planning, and weather normalization of all forecasts, not just the forecasts that use temperature as a regression variable. PG&E is currently in the testing and forecast validation phase of the Long Term Planning Tools upgrade; it is expected to be fully implemented for use in the 2023-2024 DPP.

In addition to adopting upgraded versions of LoadSEER and CYME, PG&E is implementing a customer load application database that will receive customer application data used for inputs to the forecasts directly from the enterprise resource planning software, SAP, as well as real-time updates of data changes (e.g., cancellation, change in requested load amount or date for service, etc.). Currently, PG&E's Service Planning process is separate from the DPP, and application data is transferred manually from one process to the other. Updates to the data are also completed manually. Therefore, if data, such as the requested load amount, is not updated within the DPP there is a chance that capacity projects identified to accommodate the load application(s) will be based on outdated information. The customer load application database will minimize this risk by integrating the two processes and allow for better tracking of customer application data that PG&E can use to more accurately plan capacity projects and minimize over or underbuilding. PG&E is expected to begin the implementation process of the database in Q2 of 2023 with full implementation expected for input to the 2023-2024 DPP.

PG&E is also in the process of deploying foundational operational platforms that will enable safe and efficient operations of the distribution system which is becoming increasingly complex and dynamic driven by the adoption of DERs and load growth from electrification. These include the following platforms:

ADMS: The Advanced Distribution Management System (ADMS) is PG&E's core distribution operations software tool to enable visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA), Distribution Management System (DMS), and Outage Management System (OMS) applications into a single, integrated platform and enable many new capabilities.

The ADMS is a foundational tool that will bring far-reaching benefits to PG&E, its customers, and the distribution system. Some of the benefits of ADMS include:

- Reduced cybersecurity risk from replacement of PG&E's outdated RT-SCADA system;
- Labor efficiencies from automated switching recommendations, automated switch log development, and consolidation of functionality into a single application and screen;
- Reliability improvements from instantaneous fault location, automated switching recommendations, and enablement of more flexible, model-based Fault Location, Isolation, and Service Restoration (FLISR) schemes;
- Improved safety from streamlined internal processes and automated detection and mitigation of overload conditions on non-telemetered points on the system;
- Better quality of communication to customers during outages;
- Energy savings, peak demand reduction, and greenhouse gas emissions reductions from future ADMS-managed automated Volt-Var Optimization (VVO) schemes;
- Improved management of Distributed Energy Resource (DER)-related grid issues through awareness of masked load associated with DER generation and the automated mitigation of DER-related thermal, voltage, and protection issues; and
- Enablement of Distributed Energy Resource Management System (DERMS) functionality such as the proactive dispatch of DER to mitigate real-time and forecasted grid constraints identified via the ADMS.

DERMS: PG&E's Distributed Energy Resource Management System (DERMS) will complement the foundational technology improvements and grid management tools built by the Advanced Distribution Management System (ADMS) program. The DERMS will allow PG&E to manage the added operational and programmatic complexity of ever-growing Distributed Energy Resources (DERs) and DER Programs on the PG&E grid. PG&E is planning to build a DERMS platform to deliver the following capabilities:

- Monitoring, dispatch, and program management of DER systems: DERMS will be a secure platform that enables the monitoring and dispatch of both front-of-the-meter (FTM), behind-the-meter (BTM), and aggregated DER assets with rules based on program types.
- Full integration with ADMS: DERMS will seamlessly integrate with the ADMS, building on the integrated network model and grid modeling capabilities provided by the core ADMS product.
- DER advanced situational awareness for normal and abnormal conditions: DERMS will provide additional DER visibility beyond what is typically included by an ADMS such as DER status, flexibility, availability, forecasted flexibility, and program insights.
- DER constraint management for interconnection and abnormal conditions: DERMS will enable more dynamic hosting and load serving capacity including dynamic constraints under abnormal conditions.
- Operation of DER-based deferral solutions: Examples of such solutions include projects participating in the Distribution Investment Deferral Framework (DIDF) and other alternatives to conventional infrastructure investments.

PG&E is currently in the planning phase of the DERMS deployment with initial focus on use cases related to managing dynamic distribution grid constraints with enhanced situational awareness of grid conditions (leveraging the initial ADMS deployment), operational forecasts of grid conditions in the hours/days ahead, and control of participating DERs including flexible loads. PG&E expects to pilot initial DERMS use cases at a limited scale by 2024 and will plan to scale up in subsequent years pending results.

H. PG&E's Current Local Planning Engagement Processes, Challenges, and Improvement Plans

PG&E currently manages relationships with thousands of community stakeholders, including: 47 counties; 246 cities; 62 federally recognized tribes; local, state and federal agencies; local and regional Community Based Organization (CBOs) and associations. PG&E collaborates/communicates on a variety of topics of interest to the stakeholders and communities, including: infrastructure projects, customer programs, emergency preparedness and response, service and billing inquiries, reliability, and local, state, and federal energy policy. To effectively manage communication to communities and stakeholders, various PG&E teams (e.g., Tribal Liaisons, Local Government Affairs, Low Income Programs and DAC, Public Safety Specialists, Economic Development, Customer teams) engage and coordinate these communications.

Additionally, as described in section I below, PG&E established the Regional Service Model to realign the Company around a common set of regional boundaries and establish regional leadership—the Regional Vice Presidents—to lead each region. The Regional Service Model provides an overarching structure to manage local performance, including community engagement, and installs leaders to act on issues that require authority and influence of an officer.

Communities currently help inform the DPP by submitting new service applications and through regular and as-needed PG&E engagement. PG&E will continue to leverage these existing outreach efforts to further improve engagement and communication with local and regional planning entities regarding the DPP. Engagement occurs throughout the project development and evaluation. Ultimately many factors affect a project development timeline when projects are reflected in forecasts, including processes outside of PG&E's control (e.g., permitting, environmental and land use impacts assessments, etc.). It's important to note that PG&E experiences approximately a 35% application dropout (cancelled/withdrawn) rate throughout the new service end-to-end process. Customers should contact and work with PG&E directly to provide specific details of their project in order to evaluate timelines and obtain accurate information for request the relocation, removal, upgrade, or new installation of PG&E gas and/or electric facilities for service.

In addition, as PG&E described at the December 13, 2022 Distribution Planning Community Engagement Needs Assessment Workshop,[10] PG&E leverages existing community outreach to gather information about new planned loads and other developments that can be factored into the DPP. PG&E will continue to engage in two-way dialogue with communities to solicit feedback and better understand community needs related to the DPP. Input from community stakeholders will be used to validate needs so PG&E can make informed investment decisions. The increased transparency will help customers understand when they can expect PG&E investments in their communities. And the community engagement process will be refined over time based on feedback from communities.

For example, PG&E Account Representatives conduct semi-annual discussions with our large commercial, industrial and agricultural customers to understand business priorities and connect customers with the appropriate solutions that address their needs. These meetings include gathering intelligence about customer future growth plans and when and where customers are considering adding substantial new electric or gas load. Future load growth plans, including proposed location, size, and timing, are captured and shared with PG&E Distribution Planning, Substation Planning and Transmission Planning departments, as appropriate, to build awareness of potential new loads. Included in this outreach is a more targeted effort with key EV Fleet operators to collect five to ten year EV Fleet expansion plans to incorporate into PG&E's future load forecasts.

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[10] *Presentation* slides are available online (as of April 10, 2023) at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/combined-presentations-wkshp_12132022.pdf

PG&E is also in regular discussion with large EV service providers (EVSP) to understand their long-term forecasts and include this information in the DPP. The long-term forecasting is intended to receive future electric service needs in advance of service applications so that longer lead time capacity work can be better informed. Forecasts shared can provide 5+ year visibility to planned projects where developers are actively prospecting for charging locations, while service applications are commonly only submitted <18 months from the designed energization date, which would not allow for most reactive capacity project to be completed within this time frame.

In addition, PG&E will be launching a new Distribution Planning Questionnaire in April 2023, leveraging our existing community outreach efforts. Information collected from communities on their DER/electrification plans is intended to be directional in the DPP and is not a guarantee of specific grid investments. PG&E will gather input from communities on any specific projects or plans and compare it to our forecast and if necessary make adjustments to the forecast on a case-by-case basis dependent on several factors. Communities may provide specific details as projects develop and when a new business application is submitted to PG&E and it progresses through PG&E's various interconnection/service planning processes, the project will be reflected in PG&E's forecast with higher certainty.

In addition, PG&E is launching a new layer to its Integration Capacity Analysis (ICA) public maps, to improve the directional data for customers siting new loads and to better inform customers of how to use the combined ICA, GNA, and DDOR data. This new layer would indicate directionally the status of ICA, forecast, and project data at each location to better direct customers to site new load. The layer would indicate, for a given location, whether:

- There is likely no available load capacity at this location. This means that interconnecting new load will likely require grid upgrades.
- There is likely available load capacity at this location. However, all interconnection applications would still be subject to engineering review.

- An engineering review is necessary to assess the interconnection capacity at this location, due to a planned project or a future load that may change the state of the circuit.

In addition, discussions are underway to inform local planning agencies' about long lead time planning projects. It can be advantageous for developers and customers to include the environmental impacts of new substation and transmission facilities in their Environmental Impact Report (EIR) if these new facilities will be needed to serve new load. PG&E is engaging with local planning agencies about their responsibilities for CEQA approvals and ensuring that any required electric system upgrades are included in customer EIRs.

In addition, PG&E is creating and adopting a new integrated grid planning approach to meet the multi-dimensional needs of our customers and communities and to support the state's bold climate goals. Through this approach, we are developing stable, multi-year plans to give our teams and communities visibility into what work we will do, and when we will do that work, to enable more advanced planning. The new approach will help customers better understand when they can expect new connections and upgrades in their areas. Our Regional Service Model (regionalization) is enabling us to more effectively anticipate local needs and provide a direct path to address local, emerging issues. The Regional Vice Presidents have been engaging with customers, trade associations and local officials to help raise our awareness of critical local projects and needs.

I. PG&E's Response to Local Needs and Community Engagement under the Regional Service Model

In 2021, PG&E launched the Regional Service Model to strengthen PG&E's local presence, operational performance and customer interactions. Key to this model is realigning the Company around a common set of regional boundaries and establishing regional leadership to lead each region.

In general, within this structure, the Regional Vice Presidents (RVP) develop a deep knowledge of the needs of their regions and are empowered and accountable to deliver high quality performance. The RVPs lead cross-functional operating reviews and have a shared set of key performance metrics that will align the functional leaders and the regional teams around a shared purpose of providing strong service to customers and communities. The RVPs facilitate both the tactical resolution of problems by local operations teams, and more strategic local challenges that require additional influence and resources to affect broader change, such as challenges that span multiple functions or a large geographic footprint. These challenges often require operational visibility, influential authority, and awareness of community needs to proactively address. This includes performance around local and community engagement, and any community escalations.

In regards to local needs and community engagement, the Regional Vice Presidents' presence and work in the regions has strengthened the existing collaborative relationships with local communities and customers in the regions. The Regional Vice Presidents live in the regions they serve, which opens a more direct channel of communications with the local communities. The Regional Vice Presidents focus on local customer engagement including communications, community engagement, local customer service and public safety. They provide a dedicated focus on local customer and community needs, tailor activities based on the unique needs of the region, and foster integration with the operations teams executing the work. Additionally, the Regional Vice presidents, working with local teams, act as troubleshooters with local governments and agencies on issues they are facing.

As mentioned above, visual management and operating reviews are core aspects of the PG&E's operating model and bring rapid attention and action to metrics that are off track. In 2022, PG&E adopted a new business planning process that begins with companywide planning and strategy objectives. The new planning process focuses on creating aggressive and achievable annual and long-term performance objectives, and plans that support the delivery of safe, reliable, and affordable energy.

Regional Vice Presidents are included in core aspects of the planning process, including the: Continual alignment of the operational plans to the overall company objectives; Functional and cross-functional target setting process. Through this process, regional targets (and associated regional views of the plan) are set collaboratively with operations leadership and based on risk, prior year performance and enterprise focus for the coming operating cycle. These metrics are then made visible and monitored via the operating review process defined above. PG&E's Safety and Operational Metrics (SOMs) are not distinct from PG&E's safety, delivery, quality, cost, and morale metrics and exist within the same metric review framework; these are visualized, monitored, and actioned through the operating review process. Among the level one (L1) metrics being monitored at the enterprise level, the Regional Vice Presidents are monitoring 16 in their operating reviews.

In addition to the top-level enterprise metrics established through the planning process, each Regional Vice Presidents work with key regional operations and support leaders to identify, visualize and monitor leading indicators that represent local operations per region. These metrics are subject to change based on the conditions of the regions and as each region continues to evolve their operating reviews. These metrics may also change due to changes to non-regional conditions and other company needs.

III. DPP ALIGNMENT WITH THE GENERAL RATE CASE (GRC), ELECTRIFICATION PLANNING, AND THE INTEGRATED ENERGY POLICY REPORT (IEPR)

A. Interrelationships Between the GRC, IEPR, and DPP

The California Energy Commission adopts an Integrated Energy Policy Report (IEPR) every two years with an update in the intervening years (IEPR Update). The IEPR and IEPR Update include a state-wide demand forecast that contains both load and DER growth (IEPR Forecast). PG&E uses the IEPR Forecast in its annual DPP, supplemental forecasts (e.g., Inter Agency Working Group EV forecast) along with known load applications, weather data, and peak load data, to update the annual distribution forecasts for each substation transformer, circuit, and circuit line section. The system-level forecast of electric demand and DER growth used in the DPP is based on the CEC IEPR, which is then used to identify deficiencies and associated capacity projects.

The GRC is a regulatory proceeding for the IOUs to request funding, based on a forecast of all utility operation needs over a four-year period (previously the request was for a 3-year period). In terms of distribution planning, there is a lag between the IEPR, DPP and GRC approval. For example, PG&E's 2023 GRC application utilizes the results of the 2021 DPP (i.e., 2020-2021 Forecast Cycle) which was based on the 2019 CEC IEPR. Although annual changes adopted to the IEPR Forecast will change the inputs into PG&E's DPP forecast, PG&E cannot change its GRC request in non-GRC filing years nor request additional funding once the capacity forecast is approved by the GRC. In other words, as PG&E has already filed its 2023 GRC application, any increase in load growth shown in subsequent annual DPP forecasts, will not impact the authorized GRC capacity funding for 2023 to 2026. Assuming PG&E's GRC is approved in 2023, that represents a four-year gap between when the IEPR forecast was developed (2019) and when the GRC was theoretically approved (2023).

PG&E's 2023 GRC funding request is based on a risk informed portfolio of work that puts safety first while balancing customer commitments and California's clean energy goals with affordability. In developing this portfolio, PG&E must consider such factors as risk reduction, cost, efficiencies, overall authorized GRC funding, the availability of PG&E and contractor resources, synergies with other work, and dependencies and requirements such as permitting and the different rules for working with California's counties and cities. The forecast represents a balanced portfolio that prioritizes risk mitigation work, compliance work, and regulatory and other commitments while staying within corporate capital and expense targets. In addition, in developing its 2023 GRC portfolio, the request was constrained by the targets established in the Plan of Reorganization (POR) when PG&E emerged from bankruptcy on July 1, 2020.[11] Therefore, PG&E's 2023 GRC forecast was developed around a set of guiding principles: the forecast must be risk informed; the forecast must meet key commitments made by the Company; and the forecast should be consistent with the financial targets included in PG&E's POR.

[11] PG&E discusses the POR financial targets in its GRC Application 21-06-021, Exhibit PG&E-2, Ch. 3.

One part of the overall GRC request includes distribution capacity funding. The DPP, as described in Response 1(A), evaluates and specifies projects to ensure the availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system. The DPP also generally identifies the estimated cost of each project; which in aggregate, informs the proposed capacity forecast. However, the funding ultimately requested through GRC is determined through PG&E's investment planning processes which considers the overall company GRC request and weighs the GRC guiding principles, as well as the fact that the plan may be updated throughout the year and in subsequent years as actual conditions change or new information becomes available. Therefore, the distribution capacity forecast in the GRC does not typically represent 100% of all known projects. Additionally, the approved GRC forecast may or may not reflect the proposed forecast requested if the distribution capacity funding is reduced as a result of settlement agreements or Commission decision.

Once the GRC forecast is approved, PG&E again goes through the annual investment planning processes to determine what capacity projects to fund using the capacity budget and develop a list of the final planned projects. Therefore, some projects identified in the DPP may be delayed if alternate funding cannot be secured. The investment planning process is an integrated approach to prioritize projects according to the available budget and various other factors (projects in flight, coordination with other planned work in the area, etc.).

B. Discussion on Alignment of GRC, IEPR, and DPP to Meet Load and DER Projections

Historically, the GRC, IEPR, and DPP process were fairly well aligned regarding grid infrastructure investment needed to meet the load and DER projections. As described in Response 1A, most of PG&E's planned investments have implementation timelines of less than 5 years. Therefore, the GRC had been generally aligned with the budget timeline for those planned investments.

However, as we enter a high electrification future, the system-level CEC IEPR planning forecast for Transportation Electrification has significantly changed over the last several years to reflect state policy goals and changing customer demand. PG&E supports these updates but notes that while these changes may occur on an annual basis and thus the annual DPP, the GRC is on a 4-year cycle and therefore the funding necessary to support this growth may be misaligned. An annual update in the CEC IEPR forecast will not impact the capacity forecast requested or approved in the GRC on an annual basis. As mentioned in the previous section for example, PG&E's 2023 GRC application was filed in June 2021, based on the 2019 CEC IEPR. Subsequent updates to the IEPR forecast anticipate significantly accelerating load growth in electrification, and while this will be reflected in PG&E's 2023 DPP, it is not reflected in PG&E's 2023 GRC application.[12] PG&E is concerned this misalignment will be further exacerbated as electrification continues to materialize. While PG&E fully supports the state's clean energy policy, it must ensure the IOUs have adequate resources including funding to meet the demand. In Response II.C. above, PG&E describes changes to policy that could help PG&E serve electrification load growth going forward.

C. Distribution Investments Included in the GNA/DDOR

The Distribution Investment Deferral Framework (DIDF) is part of the Competitive Solicitation Framework (CSF) developed in the DER proceeding to establish an ongoing annual process to identify, review, and select opportunities for third party-owned DERs to defer or avoid traditional capital investments in the IOUs' distribution systems.[13] Per D.18-02-004, "the central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional IOU investments that are planned to mitigate forecasted deficiencies of the distribution system."[14] One component of the DIDF process is the filing of the annual Grid Needs Assessment (GNA) report and Distribution Deferral Opportunity Report (DDOR).

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[12] PG&E's 2023 *GRC* request was based on the 2020-2021 planning cycle forecasts that used the 2019 CEC IEPR Forecast.

[13] D.18-02-*004*, p. 18.

[14] Id., p. *27*.

The GNA is a snapshot in time that includes the planning assumption data and all of the grid needs, resulting from the Distribution Planning Process, within the four distribution categories: capacity, voltage support, reliability (back-tie), and resiliency (microgrid).[15] The GNA does not report out on distribution investments.

The Distribution Deferral Opportunity Report (DDOR), as established in D.18-02-004, builds off of the GNA to present PG&E's "planned investments that provide one or more of the four distribution services adopted by D.16-12-036."[16] The DDOR also presents the Candidate Deferral Opportunity (CDO) list "that results from applying initial deferral screens to planned investments."[17]

For all DDORs filed to date (including the 2022 DDOR), PG&E included all proposed distribution planning solutions to address grid needs within the 5-year planning forecast for circuits and banks, 3-year planning forecast for line sections, and when applicable, long-lead projects beyond the planning horizon such as substations (as explained in Section II.A above) regardless of whether funding for those proposed solutions was available. As mentioned previously, the annual investment planning process determines the annual budget for the DPP and thus which proposed projects can be funded, resulting in many of the proposed distribution planning solutions not being funded within the 2023 GRC window. For the 2023 DDOR, PG&E intends to include only the proposed distribution planning solutions that are currently funded within the current planning horizon. Given current funding shortfalls, many of the proposed distribution planning solutions cannot be funded within the current planning horizon. Once funding is available and secured (potentially in a future year), the distribution planning solution can become a planned investment. As a result, the 2023 DDOR will include all planned investments (i.e., funded proposed solutions), but PG&E anticipates that the 2023 DDOR *may*

[15] Id., p. 36.

[16] Id.

[17] Id., p. 37.

include a smaller list of proposed solutions relative to past DDORs (where both funded and unfunded proposed solutions were included).

To be clear, going forward there may be grid needs identified in PG&E's 2023 GNA that do not have an associated planned investment withing the planning horizon in PG&E's 2023 DDOR. While PG&E supports utilizing DERs to meet distribution capacity needs, in practice, including planned investments that are not funded would constrain PG&E's limited budget even further because (1) DIDF contract costs are not recovered in rates immediately (they are recorded to a memorandum account for future recovery in a subsequent GRC)[18] so PG&E would need to cover the contract costs without funding until the next GRC; and (2) the grid need, particularly those outside of the GRC window, may not ultimately precipitate or may change to a degree that a distribution investment is needed regardless of the DER's presence, meaning customers must pay for the infrastructure (once funding is available) *and* pay for the DIDF DER contract costs.

IV. CONCLUSION

PG&E is undertaking substantial efforts to prepare for electrification and a high DER future. PG&E urges the Commission to rescope this proceeding to focus on how to support the utilities in meeting customer's needs during this unprecedented electrification environment, most notably by exploring additional capacity funding opportunities.

[18] D.18-02-004, Ordering Paragraphs 2.aa and 2.bb.

Respectfully submitted,

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